

§ 146.87

40 CFR Ch. I (7–1–13 Edition)

must provide the following information:

- (i) Depth to the injection zone(s);
- (ii) Injection pressure, external pressure, internal pressure, and axial loading;
- (iii) Hole size;
- (iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);
- (v) Corrosiveness of the carbon dioxide stream and formation fluids;
- (vi) Down-hole temperatures;
- (vii) Lithology of injection and confining zone(s);
- (viii) Type or grade of cement and cement additives; and
- (ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.

(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.

(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.

(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.

(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

(c) *Tubing and packer.* (1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into

contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.

(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:

- (i) Depth of setting;
- (ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;
- (iii) Maximum proposed injection pressure;
- (iv) Maximum proposed annular pressure;
- (v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;
- (vi) Size of tubing and casing; and
- (vii) Tubing tensile, burst, and collapse strengths.

§ 146.87 Logging, sampling, and testing prior to injection well operation.

(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:

(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for

Environmental Protection Agency

§ 146.88

fluid movement in the form of diverging holes are not created during drilling; and

(2) Before and upon installation of the surface casing:

(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

(3) Before and upon installation of the long string casing:

(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and

(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.

(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:

(i) A pressure test with liquid or gas;

(ii) A tracer survey such as oxygen-activation logging;

(iii) A temperature or noise log;

(iv) A casing inspection log; and

(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.

(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.

(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

(d) At a minimum, the owner or operator must determine or calculate the

following information concerning the injection and confining zone(s):

(1) Fracture pressure;

(2) Other physical and chemical characteristics of the injection and confining zone(s); and

(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).

(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

(1) A pressure fall-off test; and,

(2) A pump test; or

(3) Injectivity tests.

(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

§ 146.88 Injection well operating requirements.

(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.

(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.

(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.